

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

Valley Regional Office

INTRA-AGENCY MEMORANDUM

4411 Early Road - P. O. Box 3000 Harrisonburg, VA 22801-3000

Permit Writer	<i>Janardan Pandey</i>	Date	<i>DRAFT</i>	
Air Permit Manager		Date		
Deputy Regional Director		Date		
Memo To	Air Permit File			
Facility Name	CPV Warren LLC			
Registration Number	81391			
County-Plant I.D.	187-0041			
UTM Coordinates (Zone 17)	744.6	Easting (km)	4316.9	Northing (km)
Elevation (feet)	580			
Distance to Nearest Class I Area (select one)	7.1	SNP (km)	N/A	JRF (km)
FLM Notification Required (Y/N)	Y			
AFS Classification (A, SM, B)	A	Before permit action	A	After permit action
Pollutants for Which the Source is Title V Major	PM-10, NO _x , & CO	Before permit action	PM-10, NO _x , & CO	After permit action
PSD Major Source (Y/N)	Y	Before permit action	Y	After permit action
Pollutants for Which the Source is PSD Major	PM, PM-10, NO _x , and CO	Before permit action	PM, PM-10, NO _x , and CO	After permit action

I. Introduction

On July 30, 2004, CPV Warren LLC (CPV) was issued a Prevention of Significant Deterioration (PSD) permit to construct and operate a nominal 580-megawatt (MW) electric power generating facility in Warren County, Virginia. An extension of the permit was granted March 29, 2006. The permit was extended 18 months from its original expiration date of January 30, 2006, resulting in a new expiration date of July 30, 2007. Due to a downturn in investment in new power generation, construction of the facility has been further delayed. In an application dated May 8, 2007 (received by Valley Regional Office (VRO) May 10, 2007), CPV has requested an additional extension of the permit. In its application, CPV predicted that construction of the facility will commence no later than June 2008. Another extension of the permit was granted June 5, 2007, resulting in a new expiration date of December 5, 2009.

On July 12, 2007, VRO received an application from CPV for a significant amendment to its existing PSD permit to construct and operate an electric power generating facility. CPV has indicated in its application that the electric power needs of the area may be better served by a power generating facility with a slightly different turbine configuration, and the economic value of the project may be enhanced by a permit that allows two different turbine manufacturers. Under the current power market, CPV anticipates operating the facility with more start-ups and shut-downs than originally anticipated.

The current permit specifies only one equipment provider (General Electric) with “one-on-one” combustion turbine (CT) generator configuration with two CT generators, two heat recovery steam generators (HRSG) and two steam turbines. A “one-on-one” CT generator configuration means that each CT/HRSG is paired with its own steam turbine. CPV is requesting that the current permit be amended to allow a “two-on-one” CT generator configuration with two different turbine manufacturers (General Electric and Siemens) in addition to the currently permitted “one-on-one” CT generator configuration. A “two-on-one” CT generator configuration means that both CT/HRSG units are paired with a single steam turbine. This configuration also requires an auxiliary boiler to provide steam during plant down time and the plant start-up process.

This permit amendment application requests that the existing permit be amended to allow the option of selecting either two GE 207 FA gas turbines or alternatively two equivalent Siemens SGT6-5000F gas turbines in a “two-on-one” CTG configuration. Additionally, CPV is also requesting that a natural gas-fired auxiliary boiler be permitted in the proposed permit for this “two-on-one” CT generator configuration. There are no changes to the emergency generator and the emergency fire water pump that are permitted in the existing permit.

II. Emission Units / Process Description

The proposed permit authorizes one of three possible scenarios for the final configuration of the electrical power generation facility:

- Scenario 1 (current permit) consists of a “one-on-one” combustion turbine (CT) generator configuration with two General Electric CT generators, Model 7FA, two heat recovery steam generators, and two steam turbines.
- Scenario 2 (new) consists of a “two-on-one” CT generator configuration with two General Electric CT generators, Model 207FA, two heat recovery steam generators, one steam turbine, and one auxiliary boiler.
- Scenario 3 (new) consists of a “two-on-one” CT generator configuration with two Siemens CT generators, Model SGT6-5000F, two heat recovery steam generators, one steam turbine, and one auxiliary boiler.

Scenario 1 - Scenario 1 is same as that in the current permit. There are no changes in the emission units from the existing permit. CPV has proposed the following emission units to be constructed at this facility under this scenario:

- two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:
 - one General Electric natural-gas-fired CT generator, Model 7FA, rated at 180,000 KW and 1,717 million Btu per hour heat input (CT1 & CT2);
 - one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1 & DB2)
- one diesel-fired emergency fire water pump, rated at 2.3 million Btu per hour heat input (EG1);
- one diesel-fired emergency generator, rated at 1500 KW (EG2); and
- one 6,000 gallon distillate oil storage tank.

Scenario 2 - Equipment to be constructed at this facility under this scenario consists of:

- two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:
 - one General Electric natural-gas-fired combustion turbine (CT) generator, Model 207FA, rated at 286,200 KW and 1,944 million Btu per hour heat input (CT1 & CT2);
 - one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1 & DB2);
- one natural gas-fired auxiliary boiler, rated at 97 million Btu per hour heat input (AB1);
- one diesel-fired emergency fire water pump, rated at 2.1 million Btu per hour heat input (EG1); and
- one diesel-fired emergency generator, rated at 1500 KW (EG2); and
- one 6,000 gallon distillate oil storage tank.

Scenario 3 - Equipment to be constructed at this facility under this scenario consists of:

- two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:
 - one Siemens natural-gas-fired combustion turbine (CT) generator, Model SGT6-5000F, rated at 311,800 KW and 2,204 million Btu per hour heat input (CT1 & CT2);
 - one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 210 million Btu per hour heat input when firing natural gas (DB1 & DB2);
- one natural gas-fired auxiliary boiler, rated at 62 million Btu per hour heat input (AB1);
- one diesel-fired emergency fire water pump, rated at 2.1 million Btu per hour heat input (EG1);
- one diesel-fired emergency generator, rated at 1500 KW (EG2); and
- one 6,000 gallon distillate oil storage tank.

III. Emission Calculations

A. SCENARIO 1

Combined Cycle Units – CT Generators and Duct Burners (CC1 and CC2):

Proposed emissions are primarily products of combustion from the combined cycle units and duct burners. Emissions from the combined cycle units vary depending on ambient temperature, relative humidity, and percent operating capacity (“load”) of the unit. General Electric, the CT manufacturer, provided pollutant emissions for 26 operating scenarios reflecting various temperature, humidity, and load conditions operating in the “one-on-one” CT generator configuration. The details of these operating scenarios are listed in the original application.

There are no changes in the emission limits for all pollutants except for SO₂ and H₂SO₄ when compared to the existing permit (permit amendment dated June 5, 2007). For all pollutants (except for SO₂ and H₂SO₄), the emission calculations described in the previous engineering memos are still valid and are not discussed here. The allowable sulfur content in the natural gas used in the combustion turbines and duct burners will be reduced from 0.3 gr/100 dscf to 0.1 gr/100 dscf in this permit action. This results in a reduction in allowable sulfur dioxide (SO₂) emissions from 0.0008 lb/MMBtu to 0.0003 lb/MMBtu and from 12.2 tons/yr to 5.7 tons/yr. Allowable sulfuric acid mist (H₂SO₄) emissions will also be reduced from 0.00025 lb/MMBtu to 0.0001 lb/MMBtu and from 3.7 tons/yr to 1.9 tons/yr. See Attachment A for calculations.

Emergency Fire Water Pump and Emergency Generators (EG1 and EG2)

The proposed facility will include an emergency diesel firewater pump and an emergency generator. The emergency firewater pump will only be operated in the event of a plant fire and during testing. The emergency generator will be operated only during interruptions in normal electrical power supply to the facility or during testing. The proposed operating restriction for each unit is less than 500 hours per year, including monthly testing and maintenance.

There are no changes in the emission limits compared to the existing permit (permit amendment dated June 5, 2007). See Attachment B for calculations.

Hazardous Air Pollutants (HAP)/Toxic Pollutants

Total HAPs from the proposed facility would be 10.73 tons per year; the individual HAP emitted at the highest rate is formaldehyde at 5.7 tons per year. HAP emissions calculations are provided in Attachment 3 of CPV’s permit application dated February 4, 2003. Thus, the facility will be a minor HAP source.

B. SCENARIO 2

Combined Cycle Units – CT Generators and Duct Burners (CC1 and CC2):

Emissions from the combined cycle units vary depending on ambient temperature, relative humidity, and percent of operating capacity (“load”) of the unit. General Electric, the CT manufacturer, provided criteria pollutant emissions for 26 operating scenarios reflecting various temperature, humidity, and load conditions while operating in the “two-on-one” CT generator configuration. The details of these operating scenarios are listed in the Appendix D of the permit application dated July 11, 2007.

Short-term emissions for the CTs and DBs have been based on the maximum hourly emission rates (“worst-case” from all operating scenarios) for each pollutant, as shown in Table 1 below.

Table 1. Operating scenarios having highest short-term emissions

Pollutant	Case	% Load	Ambient T (°F)	Relative Humidity (%)	Evap. Cooling (On/Off)	Emissions (lbs/hr)
PM-10	1NG	100	0	90	Off	12.45 lb/hr
PM-10	1NG+DB	100	0	90	Off	17.56 lb/hr
NO _x	1NG	100	0	90	Off	14.3 lb/hr
NO _x	1NG+DB	100	0	90	Off	17.9 lb/hr
CO	1NG	100	0	90	Off	3.3 lb/hr
CO	1NG+DB	100	0	90	Off	7.3 lb/hr
VOC	1NG	100	0	90	Off	0.9 lb/hr
VOC	1NG+DB	100	0	90	Off	3.9 lb/hr
SO ₂	All	-	-	-	-	0.00017 lb/MMBtu
H ₂ SO ₄	All	-	-	-	-	0.00016 lb/MMBtu

Note: Please refer to Appendix D of the application for all cases. Case 1NG+DB shown above is with duct burner operation. SO₂ and H₂SO₄ emissions are same for all cases.

Annual emissions for the CTs and DBs were calculated based on the combinations of operating scenarios shown in Table 2 below. The combination, proposed by CPV, yields a more realistic “worst-case” representation for annual emissions. Annual emissions were calculated for two scenarios: one with the realistic “worst case” representation, but not at worst-case ambient conditions (such conditions would not occur for all operating hours) and also taking into account the start-up and shut-down (SUSD) emissions; the other scenario assumes that the facility can operate 8,760 hours per year without start-up and shut-down. The first scenario with SUSD emissions assumes 349 hot starts, 30 warm starts, 13 cold starts and 393 shutdown events per year for both turbines. The permitted allowable annual emissions are the worst case emissions from these two scenarios (See Attachment C).

Table 2. Operating scenario structure used as basis for annual emissions

Case	7NG	4NG	17NG +DB	7NG +DB	SUSD	Prior to SUSD	Total Hours
Temp	59	22	100	59			
Load	Base	Base	Base	Base			
InletCooler	Off	Off	Off	Off			
Duct Burner MMBtu/hr	-	-	500	500			
Evap. Cooler Status	Off	Off	On	Off			
Annual Hours with SU/SD	2961	1000	2000	2000	211	588	8760
Annual Hours Without SU/SD	3760	1000	2000	2000	-	-	8760

Note: Start-up and Shut-down (SUSD) hours are calculated assuming 349 hot starts, 30 warm starts 13 cold starts and 393 shutdown events per year for both turbines. 588 hours are assumed to be prior to SUSD events where there are no emissions.

Emergency Fire Water Pump and Emergency Generators (EG1 and EG2)

The proposed facility will include an emergency diesel firewater pump and an emergency generator. The emergency firewater pump will only be operated in the event of a plant fire and during testing. The emergency generator will be operated only during interruptions in normal electrical power supply to the facility or during testing. The proposed operating restriction for each unit is less than 500 hours per year, including monthly testing and maintenance. There are no changes in the emission limits compared to the existing permit (permit amendment dated June 5, 2007).

Auxiliary Boiler (AB1)

This scenario requires an auxiliary boiler to provide steam during plant down time and the plant start-up process. CPV has proposed one natural gas-fired auxiliary boiler, rated at 97 million Btu per hour heat input and requested annual throughput of 316 million cubic feet of natural gas for this scenario. The proposed permitted emissions from the boiler are based upon the manufacturer's specifications and requested annual throughput. The boiler emissions are summarized in Table 3. Detailed calculations are provided in Attachment D.

Table 3. Auxiliary boiler emissions

Pollutant	Emissions (lb/MMBtu)	Emissions (lb/hr)	Emissions (tons/yr)
NO _x	0.0110	1.07	1.82
CO	0.036	3.49	5.96
VOC	0.006	0.58	0.99
PM-10	0.0005	0.05	0.08
SO ₂	0.0033	0.32	0.55
H ₂ SO ₄	0.00033	0.02	0.04

Hazardous Air Pollutants (HAPs)

Total HAPs from the proposed facility under the Scenario 2 would be 6.19 tons per year; the single HAP emitted at the highest rate is formaldehyde at 3.13 tons per year.

Detailed emission calculations are provided in Appendix B of CPV's permit application dated July 11, 2007. Thus, the facility will be a minor HAP source.

C. SCENARIO 3

Combined Cycle Units – CT Generators and Duct Burners (CC1 and CC2):

Emissions from the combined cycle units vary depending on ambient temperature, relative humidity, and percent of operating capacity (“load”) of the unit. Siemens Westinghouse Power Corporation, the CT manufacturer, provided pollutant emissions for 26 operating scenarios reflecting various temperature, humidity, and load conditions while operating in the “two-on-one” CT generator configuration. The details of these operating scenarios are listed in the Appendix D of the permit application dated July 11, 2007.

Short-term emissions for the CTs and DBs have been based on the maximum hourly emission rates (“worst-case” from all operating scenarios) for each pollutant, as shown in Table 4 below.

Table 4. Operating scenarios having highest short-term emissions (CT and Duct Burners)

Pollutant	Case	% Load	Ambient T (°F)	Relative Humidity (%)	Evap. Cooling (On/Off)	Emissions (lbs/hr)
PM-10	1	100	0	90	Off	9.90 lb/hr
PM-10	7+DB	100	59	60	On	11.3 lb/hr
NO _x	1	100	0	90	Off	16.5 lb/hr
NO _x	7+DB	100	59	60	On	17.4 lb/hr
CO	7	100	59	60	On	7.2 lb/hr
CO	7+DB	100	59	60	On	12.8 lb/hr
VOC	1	100	0	90	Off	2.1 lb/hr
VOC	7+DB	100	59	60	On	4.3 lb/hr
SO ₂	1	100	0	90	Off	0.00034 lb/MMBtu
SO ₂	7+DB	100	0	90	Off	0.00031 lb/MMBtu
H ₂ SO ₄	1	100	0	90	Off	0.00013 lb/MMBtu
H ₂ SO ₄	7+DB	100	59	60	On	0.00012 lb/MMBtu

Note: Please refer to Appendix D of the application for all cases. Case 7+DB shown above is with duct burner operation.

Annual emissions for the CTs and DBs were calculated based on the combinations of operating scenarios shown in Table 5 below. The combination, proposed by CPV, yields a more realistic “worst-case” representation for annual emissions. Annual emissions were calculated for two scenarios: one with the realistic “worst case” representation, but not at worst-case ambient conditions (such conditions would not occur for all operating hours) and also taking into account the start-up and shut-down (SUSD) emissions; the other scenario assumes that the facility can operate 8,760 hours per year without start-up and shut-down. The first scenario with SUSD emissions assumes 349 start-up and 393 shut-down events per year for both turbines. The permitted allowable annual emissions are the worst case emissions from these two scenarios (See Attachment E).

Table 5. Operating scenario structure used as basis for annual emissions (CT and Duct Burner)

Case	7	4	15+DB	7+DB	SU	SD	Prior to SUSD	Total Hours
Temp	59	22	100	59				
Load	Base	Base	Base	Base				
Duct Burner MMBtu/hr	-	-	194	210				
Evap. Cooler Status	Off	Off	On(85%)	On(85%)				
Annual Hours with SU/SD	2,780	1000	2000	2000	196	196	588	8760
Annual Hours Without SU/SD	3760	1000	2000	2000	-	-	-	8760

Note: Start-up and Shut-down (SUSD) hours are calculated assuming 393 start-up and 393 shut-down events per year for both turbines. 588 hours are assumed to be prior to SUSD events where there are no emissions.

Emergency Fire Water Pump and Emergency Generators (EG1 and EG2)

The proposed facility will include an emergency diesel firewater pump and an emergency generator. The emergency firewater pump will only be operated in the event of a plant fire and during testing. The emergency generator will be operated only during interruptions in normal electrical power supply to the facility or during testing. The proposed operating restriction for each unit is less than 500 hours per year, including monthly testing and maintenance.

There are no changes in the emission limits compared to the existing permit (permit amendment dated June 5, 2007).

Auxiliary Boiler (AB1)

This scenario requires an auxiliary boiler to provide steam during plant down time and the plant start-up process. CPV has proposed one natural gas-fired auxiliary boiler, rated at 62 million Btu per hour heat input and requested annual throughput of 201 million cubic feet of natural gas. The proposed permitted emissions from the boiler are based upon the manufacturer's specifications and requested annual throughput. The boiler emissions are summarized in Table 6. Detailed calculations are provided in Attachment F.

Table 6. Auxiliary boiler emissions

Pollutant	Emissions (lb/MMBtu)	Emissions (lb/hr)	Emissions (tons/yr)
NO _x	0.0110	0.68	1.16
CO	0.036	2.22	3.78
VOC	0.006	0.37	0.63
PM-10	0.0005	0.03	0.05
SO ₂	0.0033	0.20	0.35
H ₂ SO ₄	0.0003	0.02	0.03

Hazardous Air Pollutants (HAPs)

Total HAPs from the proposed facility under the Scenario 3 would be 6.41 tons per year; the single HAP emitted at the highest rate is formaldehyde at 3.31 tons per year. Detailed emission calculations are provided in Appendix B of CPV's permit application dated July 11, 2007. Thus, the facility will be a minor HAP source.

IV. Regulatory Review and Considerations

A. 9 VAC 5 Chapter 80, Article 8 - PSD Major New Source Review

CPV is a PSD major source that is within 10 km of a Class I area. The proposed amendment does not result in an emissions increase exceeding the significance levels in 9 VAC 5-80-1700 *et seq.*, so the proposal is not subject to PSD permitting (See Table 7 below). The "significant emissions increases" are calculated for all three permitted scenarios. Since the facility has not yet been constructed, whether significant emissions increase will occur due to the proposed amendment is determined by comparing the facility's potential to emit (PTE) before the changes (as reflected in the existing PSD permit) with the facility's potential to emit after the changes (as reflected in permitted emission limits in the proposed amendment).

Hourly net emission increases from the amendment must also be evaluated since CPV is a PSD major source that is within 10 km of a Class I area. Any net emission increase from a PSD major source which results in a 1 µg/m³ (24 hour average) impact on the Class I area is subject to PSD permitting. Previous modeling of the facility's maximum short-term emission rate demonstrated that the maximum impact on Class I area (Shenandoah National Park) would be less than 1 µg/m³ for 24-hour averaging period.

Since the facility-wide maximum short-term emission rate for the proposed amendment for any pollutant will not increase above the facility-wide maximum emission rate previously modeled, it can be concluded that the 24-hour average impact of any pollutant will remain well below the 1 $\mu\text{g}/\text{m}^3$ significance threshold.

The modeling analysis is discussed in further detail in Section VI of this memo.

Table 7 Proposed emission increases/decreases vs. PSD significant increase level

	Pollutant	Scenario 1 (GE 7FA)	Scenario 2 (GE 207 FA)	Scenario 3 (Siemens)	Existing Permit Limits
Plant Totals Potential to Emit (tpy)	NO _x	148.2	144.3	144.7	148.2
	CO	100.8	111.2	139.8	100.8
	VOC	22.9	31.1	39.5	22.9
	PM-10	134.0	129.2	86.3	134.0
	SO ₂	5.7	3.5	6.3	12.2
	H ₂ SO ₄	1.9	2.7	2.5	3.7
					PSD Significant Increase Threshold
Plant Totals Increase or (Decrease) Relative to Existing Permit Limits (tpy)	NO_x	0.0	(3.9)	(3.5)	40.0
	CO	0.0	10.4	39.0	100.0
	VOC	0.0	8.2	16.6	40.0
	PM-10	0.0	(4.8)	(47.7)	15.0
	SO₂	(6.5)	(8.7)	(5.9)	40.0
	H₂SO₄	(1.8)	(1.0)	(1.2)	7.0

Note: Please refer to the Attachment G for PTE calculations for all three scenarios.

Accordingly, the proposed project (the proposed amendment which includes all three scenarios) will not constitute a major modification; therefore, PSD review is not triggered.

Although PSD review is not triggered, the proposed changes are subject to the permitting requirements of 9 VAC 5-80-1955 in 9 VAC 5 Chapter 80, Article 8 of the Regulations for a significant amendment to the existing PSD permit dated July 30, 2004 as amended March 29, 2006 and June 5, 2007.

B. 9 VAC 5 Chapter 80, Article 6 – Minor New Source Review

As shown in Table 7 above, VOC emissions for Scenario 3 exceed the modified source emission rate exemption level as defined in 9 VAC 5-80-1320 D for permitting applicability. Therefore, the proposed Scenario 3 is subject to the permitting requirements in 9 VAC 5 Chapter 80, Article 6.

C. 9 VAC 5 Chapter 50, Part II, Article 5 – NSPS

40 CFR 60 Subpart KKKK (NSPS for Stationary Combustion Turbines)

Subpart KKKK, promulgated July 6, 2006, applies to the combustion turbines, heat recovery steam generators, and the duct burners. Subpart KKKK limits emissions from each combustion turbine to 15 ppm NO_x (at 15% O₂) and 0.0600 lb SO₂/MMBtu heat input (40 CFR 60.4320 and 60.4330). The proposed permit limits for NO_x and SO₂ from the combustion turbines (for all three scenarios), derived from Best Available Control Technology (BACT) determinations, are more stringent than the Subpart KKKK standards and will therefore serve to implement them. Subpart KKKK limits emissions from each duct burner to 54 ppm NO_x (at 15% O₂) (40 CFR 60.4320). The proposed permit limits for NO_x and SO₂ from the combustion turbines (for all three scenarios), derived from Best Available Control Technology (BACT) determinations, are more stringent than the Subpart KKKK standards and will therefore serve to implement them.

Compliance requirements for Subpart KKKK include the following:

- operate and maintain the combustion turbines, air pollution control equipment and monitoring equipment consistent with good air pollution control practices at all times (40 CFR 60.4333)
- demonstrate compliance by annual performance testing, continuous emissions monitoring system (CEMS) or continuous parametric monitoring system (40 CFR 60.4340). A CEMS installed and certified according to Appendix A of 40 CFR 75 (Acid Rain requirements) meets the Subpart KKKK requirement (40 CFR 60.4345).
- develop a Quality Assurance plan for the CEMS; a plan developed to comply with Appendix B of 40 CFR 75 meets the Subpart KKKK requirement.
- perform an initial stack test if using a NO_x-diluent CEMS (40 CFR 60.4405 and 60.8)

The current permit includes requirements, derived from other programs, to install and operate a CEMS and a CEMS Quality Assurance plan in accordance with Acid Rain requirements (40 CFR 75) and to conduct an initial stack test for NO_x.

Subpart KKKK also stipulates how to use the CEMS data to identify excess emissions (40 CFR 60.4350) and criteria for exemption from fuel monitoring requirements (40 CFR 60.4365).

40 CFR 60.4375 and 60.4395 requires semi-annual reporting of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c).

40 CFR 60 Subpart IIII (NSPS for Stationary Compression Ignition Internal Combustion Engines)

Subpart IIII was promulgated July 6, 2006, and applies to the emergency generator and the firewater pump. The rule designates emission standards for non-methane

hydrocarbon (NMHC) and nitrogen oxides (NO_x) combined, carbon monoxide (CO) and particulate matter (PM) for each unit, as shown below:

40 CFR 60 Subpart IIII emission standards applicable to CPV diesel engines (g/hp hr)

	Firewater pump (EG1)	Emergency generator (EG2)
NMHC + NO _x	3.0	4.8
CO	2.6	2.6
PM	0.15	0.15

The limits currently in the permit for the emergency generator and emergency fire pump are derived from the Subpart IIII standards. There are no changes to the emission limits for these emergency units.

Subpart IIII includes the following fuel requirements, derived from 40 CFR 60.4207:

- Beginning October 1, 2007, diesel fuel must meet the standards in 40 CFR 80.510(a)
- Beginning October 1, 2010, diesel fuel must meet the standards in 40 CFR 80.510(b)

The following monitoring and compliance requirements, derived from 40 CFR 60.4209 and 60.4211, apply to each emergency engine:

- the requirement to install a non-resettable hour meter on each engine prior to its startup
- the requirement to operate and maintain each engine according to the manufacturer's instructions
- the requirement that the emergency engine purchased be certified to the emission standards in 40 CFR 60.4204(b), or 40 CFR 60.4205(b) or (c)

Additionally, a condition has been added to the amended permit requiring compliance with 40 CFR 60 Subpart IIII requirements except where the permit is more stringent.

40 CFR 60 Subpart Dc (NSPS for Small Industrial-Commercial-Institutional Steam Generating Unit)

40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to the auxiliary boiler. All applicable requirements from the regulation have been incorporated into the proposed permit. The only requirement for boiler burning natural gas is keeping records of natural gas combusted. Since the potential sulfur dioxide emissions rate of the boiler is less than 0.32 lb/MMBtu, the facility is required to keep records of the natural gas combusted during each calendar month. Additionally, a condition has been added to the amended

permit requiring compliance with 40 CFR 60 Subpart Dc requirements except where the permit is more stringent.

40 CFR 60 Subpart Da (NSPS for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978)

Subpart KKKK specifically exempts units that are covered by the rule from the requirements of 40 CFR 60 Subpart Da (NSPS for Electric Utility Steam Generating Units, applicable to the proposed duct burners). Subpart KKKK applies to the proposed duct burners and the rule exempts subject duct burners from the requirements of 40 CFR 60 Subpart Da. Accordingly, Subpart Da is no longer applicable to the duct burners.

40 CFR 60 Subpart GG (NSPS for Stationary Gas Turbines)

Subpart KKKK specifically exempts units that are covered by the rule from the requirements of 40 CFR 60 Subpart GG (NSPS for Stationary Gas Turbines, applicable to the turbines). Subpart KKKK applies to the proposed turbines and the rule exempts subject turbines from the requirements of 40 CFR 60 Subpart GG. Accordingly, Subpart GG is no longer applicable to the turbines.

D. 9 VAC 5 Chapter 60, Part II, Article 1 - NESHAPS

There are no applicable requirements under this Chapter (i.e., under 40 CFR Part 61).

E. 9 VAC 5 Chapter 60, Part II, Article II – MACT

Major source thresholds for HAPs are 10 tons per year for an individual HAP or 25 tons per year total HAPs. Accordingly, CPV is not a major source of HAP and is not subject to requirements under 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants from Source Categories, or Maximum Achievable Control Technology (MACT) standards), including “case-by-case” MACT requirements.

The Combustion Turbine MACT (40 CFR Part 63, Subpart YYYY) will apply to CTs located at major HAP sources. Since CPV is not a major source of HAP, the proposed facility would not be subject to this MACT.

F. 9 VAC 5 Chapter 60, Part II, Article 5 – Emission Standards for Toxic Pollutants from New and Modified Sources

According to 9 VAC 5-60-300 C 7, emissions of toxic pollutants from generators or boilers burning natural gas is not subject to the toxic pollutant standards in 9 VAC 5-60-300. Accordingly, the electric generating units proposed by CPV are not subject to the toxic pollutant standards in 9 VAC 5-60-300.

V. Best Available Control Technology Review (BACT) (9 VAC 5-50-260)

SCENARIO 1: The BACT analysis for Scenario 1 is addressed in the engineering memo for the recent permit amendment (June 5, 2007). The only changes to the BACT analysis for Scenario 1 is reduction of natural gas sulfur content.

Natural gas sulfur content: The allowable sulfur content in the natural gas used in the combustion turbines and duct burners will be reduced from 0.3 gr/100 dscf to 0.1 gr/100 dscf in this permit action. This results in a reduction in allowable sulfur dioxide (SO₂) emissions from 0.0008 lb/MMBtu to 0.0003 lb/MMBtu and from 12.2 tons/yr to 5.7 tons/yr. Allowable sulfuric acid mist (H₂SO₄) emissions will also be reduced from 0.00025 lb/MMBtu to 0.0001 lb/MMBtu and from 3.7 tons/yr to 1.9 tons/yr. Note that SO₂ was not subject to PSD BACT because potential emissions were below significance levels triggering such a review under PSD. H₂SO₄ was subject to PSD BACT during the original permit issuance on July 30, 2004. However, it is no longer subject to PSD BACT.

The following description section provides the BACT analysis for combined cycle combustion turbines and auxiliary boiler for Scenario 2 (GE207FA) and Scenario 3 (Siemens SGT6-5000). BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental, and economic impacts. The tables shown in Attachment H summarize the proposed CCCT emissions of PM-10, NO_x, CO, SO₂, VOC and H₂SO₄ for the GE207FA (Scenario 2) and Siemens SGT6-5000 (Scenario 3). Similarly the tables shown in Attachment I summarize the proposed auxiliary boiler emissions for both scenarios (Scenarios 2 and 3)

Combined-Cycle Combustion Turbine (CCCT)

NO_x Control

Combustion turbines and the associated HRSGs are responsible for most of the emissions from the facility. The following control technologies were identified by CPV as applicable to NO_x treatment for combined cycle combustion turbines.

- Selective Catalytic Reduction (SCR)
- EMx
- Dry Low NO_x Combustors
- Water and Steam Injection Control

Selective Catalytic Reduction (SCR)

SCR is a post-combustion control. Aqueous ammonia (NH₃) is injected into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, NH₃ reacts with NO_x contained within the exhaust gas to form nitrogen gas (N₂) and water (H₂O).

EM_x

EM_x (formerly SCONO_x[™]) is a trade name for a proprietary NO_x control technology marketed by EmeraChem (formerly Goal Line Technologies). EM_x uses a potassium carbonate coated catalyst to oxidize CO to carbon dioxide and reduce NO_x to N₂ and water. The EM_x bed preferentially absorbs sulfur compounds. EM_x has been used on a few turbine applications in the last ten years as an alternative to the SCR. The largest projects which have employed this technology are one 43-MW Alstom GTX-100 at the Redding Electric Utility and one 22-MW GE LM2500 at the Federal Cogeneration facility. CPV concluded that EM_x is not a practicable alternative to SCR technology for this project as EM_x technology has been utilized on only a handful of units that are a fraction of the size of the proposed GE 207 FA and Siemens SGT6-5000F CTGs.

Dry Low NO_x Combustors

Typical gas turbines operate at fuel to air ratio of 1:1. This is the condition at which the highest combustion temperature and quickest combustion reaction (including NO_x formation) occurs. Fuel to air ratios below 1:1 are fuel lean and fuel to air ratios above 1:1 are fuel-rich. The rate of NO_x production falls off dramatically as the flame temperature decreases.

Dry Low NO_x (DLN) combustors typically are two-staged premixed combustors designed for use with natural gas fuel. The first stage serves to thoroughly mix the fuel and air and to deliver a uniform, lean, unburned fuel-air mixture to the second stage.

Water and Steam Injection

Water and steam injection systems inject deionized water or extracted from the steam turbine into the combustors of a gas turbine. This has the dual effect of lowering the peak flame temperatures and enhancing performance by the large increase in volume associated with the phase change of water or superheating of steam injected to the flame zone.

BACT Determination: Dry Low NO_x Combustion and Selective Catalytic Reduction (SCR)

CPV has proposed a combination of the dry low-NO_x combustion and selective catalytic reduction (SCR) for both scenarios (GE 207 FA and Siemens SGT6-5000F). Both options will achieve 2 ppmvd at 15% O₂. CPV has also submitted a table summarizing the recent BACT determinations (Appendix E of the Permit Application dated July 11, 2007). None of these determinations have NO_x emissions limits more stringent than the options proposed for this project. The draft permit proposes use of SCR to control NO_x emissions from the CCCT to the following levels:

Scenario 2 (GE 207FA Option):

- 2.0 ppmvd (17.9 lbs/hr) with duct burner firing
- 2.0 ppmvd (14.3 lbs/hr) without duct burner firing

Scenario 3 (Siemens SGT6-5000F Option):

- 2.0 ppmvd (17.4 lbs/hr) with duct burner firing
- 2.0 ppmvd (16.5 lbs/hr) without duct burner firing

Compliance with all limits is to be based on a one-hour average. DEQ concurs with the applicant's analysis that a combination of the dry low-NO_x combustion and selective catalytic reduction (SCR) for both scenarios (GE 207 FA and Siemens SGT6-5000F) to achieve 2 ppmvd at 15% O₂ represents BACT for the CCCT.

Carbon monoxide (CO) Control

CO emissions are formed in the exhaust of a combustion turbine as a result of incomplete combustion of the fuel. The following control technologies were identified by CPV as applicable to CO treatment for combined cycle combustion turbines.

- Oxidation Catalyst
- DLN
- Clean Fuels / Good Combustion Practices

Oxidation Catalyst

The top control for combustion turbine CO emissions is an oxidation catalyst. Excess oxygen in the turbine exhaust reacts with CO and VOC over the catalyst bed to promote the oxidation and formation of CO₂ and H₂O.

DLN

DLN is sometimes cited as BACT for the combustion turbines. The formation of CO is the result of incomplete combustion of fuel. By controlling the combustion process, CO emissions can be minimized.

Clean Fuels / Good Combustion Practices

Use of clean fuel and good combustion practices are often cited as BACT

BACT Determination: Good Combustion Practices and Oxidation Catalyst

The applicant proposed an oxidation catalyst and good combustion practices to control CO emissions to the following levels, all corresponding to 15% O₂:

Scenario 2 (GE 207FA Option):

- 1.5 ppmvd (7.3 lbs/hr) with duct burner firing
- 1.2 ppmvd (3.3 lbs/hr) without duct burner firing

Scenario 3 (Siemens SGT6-5000F Option):

- 2.5 ppmvd (12.8 lbs/hr) with duct burner firing
- 1.8 ppmvd (7.2 lbs/hr) without duct burner firing

DEQ concurs with the applicant's BACT proposal of utilizing an oxidation catalyst and good combustion practices to limit CO emissions to the level described above.

PM/PM-10 control

The most effective PM/PM-10 emissions control for combustion turbines is the use of clean burning fuels, such as natural gas and good combustion practices. Because of the high pressure drops associated with CTs and the low concentrations of PM-10 present in the exhaust gas, post-combustion controls such as baghouses, scrubbers, and electrostatic precipitators are not generally considered feasible.

CPV has submitted a table summarizing the BACT determinations for large natural gas fired combustion turbines in the last five years (Appendix E of the Permit Application dated July 11, 2007). Review of the determinations indicate that for one project, Sacramento Municipal Utility District, the PM-10 emission rate is reported to be more stringent than the rates for proposed GE 207 FA and Siemens SGT6-5000F CTs. This project has been built and is operating. For a second project, Klamath Generation, LLC, the PM-10 emission rate is reported to be more stringent than the rates for the GE 207 FA and Siemens SGT6-5000F CTG. This project has not been built and the vendor has not been selected. For both of these projects, the PM-10 emissions are controlled by burning clean fuel and use good combustion practices.

The PM-10 emission rate presented for both options (Scenarios 2 and 3) are the lowest values that the vendors will guarantee. Therefore, BACT for PM/PM-10 from the CTs is limiting the fuel fired in the CTs to pipeline-quality natural gas having a maximum sulfur content of 0.0003 percent by weight (clean fuel) and good combustion practices.

BACT Determination: Good Combustion Practices and Clean Fuel

The draft permit proposes PM-10 emissions from the CCCT to the following levels:

Scenario 2 (GE 207FA Option):

- 17.56 lbs/hr and 0.0084 lb/MMBtu with duct burner firing (peak load)
- 12.45 lbs/hr and 0.0078 lb/MMBtu without duct burner firing (peak load)
- 12.38 lbs/hr and 0.0091 lb/MMBtu (80% load)
- 12.32 lbs/hr and 0.0107 lb/MMBtu (60% load)

Scenario 3 (Siemens SGT6-5000F Option):

- 11.30 lbs/hr and 0.0049 lb/MMBtu with duct burner firing
- 9.90 lbs/hr and 0.0050 lb/MMBtu without duct burner firing

DEQ concurs with the applicant's BACT proposal of utilizing good combustion practices and burning natural gas to limit PM/PM-10 emissions to the level described above.

VOC Control

The applicant has proposed to control VOC using good combustion practices in the CT and an oxidation catalyst. The oxidation catalyst is proposed for the primary purpose of controlling CO emissions and is part of the applicant's CO BACT approach. However, the catalyst has the added benefit of reducing VOC emissions as well. The applicant has therefore proposed VOC limits as follows, all at 15% O₂:

Scenario 2 (GE 207FA Option):

- 1.5 ppmvd (3.9 lbs/hr) with duct burner firing
- 0.7 ppmvd (0.9 lbs/hr) without duct burner firing

Scenario 3 (Siemens SGT6-5000F Option):

- 1.4 ppmvd (4.3 lbs/hr) with duct burner firing
- 0.7 ppmvd (2.1 lbs/hr) without duct burner firing

BACT Determination: Good Combustion Practices and Oxidation Catalyst

Please note that VOC was not subject to PSD BACT. The BACT is for minor new source review (9 VAC 5 Chapter 80, Article 6).

Auxiliary Boiler (AB1)

The applicant identified low NO_x burners, flue gas recirculation (FGR), SCR and Selective Non-Catalytic Reduction (SNCR) as possible control technologies for NO_x. SCR and SNCR are seldom used on natural gas-fired package boilers, as FGR and LNB achieve emission reductions in a more cost-effective approach. An oxidation catalyst for the control of VOC and CO is not considered cost effective. Since the boiler will be operated with natural gas, which results in low sulfur dioxide and particulate emissions, add-on controls were not considered for these pollutants because the realizable reduction in emissions is far too small for the controls to be cost-effective.

BACT Determination LNB and FGR with good combustion practices

The applicant proposed using LNB and FGR to achieve NO_x emissions of 0.011 lb/MMBtu. Good combustion practices and the use of natural gas have been identified and accepted as BACT for CO, VOC, PM-10 and SO₂.

VI. Dispersion Modeling

Results of the Class I and Class II air quality modeling analyses conducted in support of the original permit application are on file in separate modeling reports dated September 12, 2003 and June 9, 2003, respectively. The analyses demonstrated that the proposed emission levels did not cause or significantly contribute to a violation of the National Ambient Air Quality Standards (NAAQS) in a Class II area or to an exceedance of the allowable increment or an adverse impact on any air quality related value in a Class I area (as determined by the Federal Land Manager, in CPV's case, the National Park Service (NPS)). NPS took the lead role for US Forest Service for air quality review due to proximity of the proposed site to the Shenandoah National Park.

The proposed amendment will improve or have no perceptible affect on air quality. The analysis of the proposed changes demonstrates that there will be minimal differences with respect to both the existing air permit and the data used to perform the dispersion modeling analyses that supported the original permit application for this project. See Attachment J for the DEQ air quality modeling analysis. Also, see Attachment K for a letter from NPS concurring with this finding.

VII. Boilerplate Deviations

The following changes have been made to the July 30, 2004 permit as amended March 29, 2006 and June 5, 2007. The boilerplate language has been updated.

- *Application:* The date of CPV permit significant amendment application has been added and updated to new boilerplate language.
- *Condition 2 (Equipment list):* Equipment list for Scenarios 2 and 3 added. Scenario 1 is the same as in the existing permit.
- *Condition 10 (Fuel):* The allowable sulfur content in the natural gas used in the combustion turbines and duct burners has been reduced from 0.001% by weight (0.3 gr/100 dscf) to 0.1 gr/100 dscf (0.0002% by weight) in this permit action.
- *Condition 11 (Fuel Throughput):* The fuel throughput for Scenarios 2 and 3 are added.
- *Condition 12 (Fuel Monitoring):* This requirement has been revised to reflect the requirements of 40 CFR 60 Subpart KKKK. There is no longer a requirement to monitor and record the nitrogen content of the natural gas.
- *Condition 13 (Short-Term Emission Limits):* Short-term emission limits resulting from the BACT review for Scenarios 2 and 3 have been added. There are no changes in the emission limits for any pollutant except for SO₂ and H₂SO₄ for Scenario 1. Due to a reduction in sulfur content in the natural gas from 0.3 gr/100 dscf to 0.1 gr/100 dscf, allowable sulfur dioxide (SO₂) emissions have been reduced from 0.0008 lb/MMBtu to 0.0003 lb/MMBtu. Also, allowable sulfuric acid mist (H₂SO₄) emissions have been reduced from 0.00025 lb/MMBtu to 0.0001 lb/MMBtu.

- *Condition 14 (Annual Emission Limits)*: Annual emission limits for Scenarios 2 and 3 have been added. There are no changes in the emission limits for any pollutant except for SO₂ and H₂SO₄ for Scenario 1. Due to a reduction in sulfur content in the natural gas from 0.3 gr/100 dscf to 0.1 gr/100 dscf, allowable sulfur dioxide (SO₂) emissions have been reduced from 12.2 tons/yr to 5.7 tons/yr. Also, allowable sulfuric acid mist (H₂SO₄) emissions have been reduced from 3.7 tons/yr to 1.9 tons/yr.
- *Condition 15 (Startup/Shutdown)*: Condition has been revised to reflect the shutdown definitions for Scenarios 2 and 3.
- *Condition 16 (Emission Limits: Duct Burners)*: Since the duct burners are now subject to 40 CFR 60 Subpart KKKK, the condition has been revised to reflect this change. NO_x is the only pollutant regulated under Subpart KKKK.
- *Condition 21 (NO_x Budget Trading Requirements)*: Condition has been revised because emission units which were subject to NO_x Budget Trading Requirements will be subject to the CAIR NO_x program requirement.
- *Condition 31 (CEMS)*: Condition has been revised to include CEMS requirement for CO. There are no changes to CEMS requirements for NO_x and SO₂.
- *Condition 35 (Records)*: Condition has been revised to include recordkeeping requirements for the auxiliary boiler for Scenarios 2 and 3.
- *Condition 38 (Stack Test – Duct Burners)*: Since the duct burners are subject to 40 CFR 60 Subpart KKKK, the condition has been revised to reflect this change. The facility shall comply with the NO_x emission limits for duct burners by complying with the NO_x emission limits for combined cycle unit.
- *Condition 39 (Stack Test – Combined Cycle Units)*: Initial performance tests for NO_x and SO₂ have been revised to reflect 40 CFR 60 Subpart KKKK requirements. The facility shall comply with the NO_x emission limits for duct burners by complying with the NO_x emission limits for combined cycle unit.
- *Condition 41 (Fuel Testing)*: This condition is revised to reflect 40 CFR 60 Subpart KKKK requirements.
- *Condition 45 (Initial Notification)*: This condition is revised to include a notification requirement for selection of one of the three possible scenarios (Scenarios 1, 2 or 3) for the final configuration of the electrical power generation facility not less than 30 days prior to construction commencement of the facility.

Also, requirements related to auxiliary boiler have been added for Scenarios 2 and 3.

VIII. Compliance Demonstration

A. Stack testing requirements

The permit requires initial compliance testing for NO_x, SO₂, CO, PM-10, and VOC on each combined cycle unit for all three possible scenarios. For Scenarios 2 and 3, the permit requires initial compliance testing for NO_x, and CO on the auxiliary boiler. The need for periodic performance testing will be evaluated during processing of the Title V permit for the facility based on the results of the initial testing and operating data. A condition allowing DEQ to require additional testing has been included in the permit.

B. Fuel testing requirements

The permit requires testing of fuel to determine the sulfur content of the natural gas.

C. Visible emissions evaluations

A visible emissions evaluation (VEE), concurrent with the initial CT stack test, is required by the permit. Periodic CT stack visible emission inspections, which trigger a VEE according to EPA Method 9 if visible emissions are observed, have been included in the permit.

Also, a visible emissions evaluation (VEE), concurrent with the initial auxiliary boiler stack test, is required by the permit, for Scenarios 2 and 3. Periodic auxiliary boiler stack visible emission inspections, which trigger a VEE according to EPA Method 9 if visible emissions are observed, have been included in the permit.

D. Continuous emissions monitoring systems (CEMS)

The permit requires that the CT stacks be equipped with CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain program) for NO_x and SO₂ (unless an alternative method of determining SO₂ emissions has been approved for that purpose). In addition, CEMS for CO shall be installed on each CT meeting the requirements of 40 CFR Part 60.

In addition to the CEMS, the draft permit requires CPV to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance.

E. Recordkeeping requirements

- Compliance with NO_x and CO emission limits for the CCCTs will be determined using Continuous Emission Monitoring Systems (CEMS);
- Compliance with SO₂ emission limits will be determined through fuel sulfur monitoring and records of fuel usage; and

- VOC, CO, and PM-10 emission factors (lb/ MMbtu) will be verified during initial compliance testing. Since annual emission limits for these pollutants are based upon 8760 hours of operation with each unit operating at worst case conditions, compliance with annual emission limits can be demonstrated with fuel throughput records. Accordingly, monthly record keeping of “rolling” 12-month totals is required for natural gas throughput to each turbine and to each duct burner.

Additionally, the permit requires that the following records be kept:

- Time, date, and duration of each CT startup, shutdown, reduced load, and malfunction period;
- Continuous records of heat input and power output for each CT;
- Emissions calculations sufficient to verify compliance with the annual emission limits in Conditions 14, 28, and 29 (calculated monthly as the sum of each consecutive 12-month period), and records sufficient to allow calculation of actual annual emissions from the remainder of the facility. Calculation methods are to be approved by the Director, Valley Regional Office;
- CEMS data, calibrations and calibration checks, percent operating time, and excess emissions;
- Annual operating hours of the emergency generator and the firewater pump, calculated monthly as the sum of each consecutive 12-month period;
- Fuel supplier certifications;
- Operation and monitoring records for each SCR system and each oxidation catalyst;
- Ammonia slip monitoring results;
- Scheduled and unscheduled maintenance and operator training; and
- Results of all stack tests, VEEs, visible emissions inspections, and performance evaluations.

For Scenarios 2 and 3, the permit requires following records be kept:

- Monthly and annual throughput of natural gas to the auxiliary boiler (AB1) calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- Records to verify sulfur content of pipeline natural gas as required in Condition 31.
- Emissions calculations sufficient to verify compliance with the annual emission limitations in Condition 33, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the Director, Valley Region.

The records must be available for DEQ inspection and maintained for five years.

IX. Title V Review - 9 VAC 5 Chapter 80, Article 1

The Title V permit application will be due within 12 months of startup. Since construction has not commenced on this project, Title V status is not affected by this permit action.

X. Site Suitability

There are no changes in site suitability from the original application.

XI. Public Participation

A. Applicant Informational Briefing

In accordance with Section 9 VAC 5-80-1775 B. of the Regulations, the applicant held an informational briefing at 5:30 p.m. on August 28, 2007 at the Warren County Government Center in Front Royal. As required, the briefing was advertised in the Northern Virginia Daily at least 30 days in advance (on July 28, 2007).

B. Public Briefing

9 VAC 5-80-1870 F.3 specifies that a briefing be scheduled prior to the public comment period if appropriate. VRO has scheduled a public briefing at 7:00 p.m. on November 8, 2007 at the Celebration Hall, North Warren Volunteer Fire & Rescue – Company 10, 89 Rockland Road in Front Royal, Virginia. The briefing requires a 30-day (at minimum) notification period. A legal advertisement for the briefing was placed in the Northern Virginia Daily on October 9, 2007.

C. Public Hearing

In accordance with 9 VAC 5-80-1775 F.6, VRO will hold a public hearing to accept comments on the air quality impact of the proposed source, alternatives to the source, the control technology required, and other appropriate considerations on December 10, 2007 at the Celebration Hall, North Warren Volunteer Fire & Rescue – Company 10, 89 Rockland Road, Front Royal, Virginia. A legal advertisement for the hearing will be published in the Northern Virginia Daily newspaper on November 9, 2007.

D. Documents Concerning Public Comment Period

Copies of the documents used in development of the draft permit are available for review at VRO along with a copy of the current permit. Additionally, prior to the information meeting held August 28, 2007, a copy of CPV's permit application was placed in the Samuels Public Library in Front Royal. Upon completion of the application analysis and prior to publication of the notification for the public briefing, the draft permit and draft engineering analysis will be available at the Samuels Public Library and will remain available for review throughout the public comment period. The draft permit and draft engineering analysis will also be accessible from DEQ's website at www.deq.virginia.gov.

E. Notification of Other Government Agencies

Environmental Protection Agency (EPA)

DEQ's initial letter of determination was provided to EPA Region III on July 24, 2007. EPA will be provided with a copy of the draft permit and will be notified of the public comment period and the final determination on permit issuance.

Federal Land Managers

Because of CPV's proximity to SNP, a protected Class I area, DEQ has worked with the Federal Land Managers (FLMs) whose responsibility it is to oversee such areas. Both the National Park Service (NPS) and U.S. Forest Service (USFS) were provided copies of CPV's permit application on July 16, 2007.

Upon completion of DEQ's application analysis, DEQ will provide the FLMs a copy of the draft permit and will be notified of the public comment period and the final determination on permit.

Localities particularly Affected

In accordance with Section 10.1-1307.01 of the Air Pollution Control Law of Virginia, a copy of the public notice for the briefing and hearing will be sent to the chief elected official, the chief administrative officer and the planning district commission for those localities that will be potentially affected.

XII. Other Considerations

The extended construction deadline is 18 months from the effective date of the requested permit amendment.

The policy memo related to interim implementation of new source review for PM-2.5 remains in effect (See Attachment L). As per this memo, DEQ shall use PM-10 as a surrogate for PM-2.5 for the purpose of implementing major new source review.

XIII. Recommendation

Approval to proceed with public comment period is recommended.

Attachments

Attachment A:	Derivation of SO ₂ and H ₂ SO ₄ revised limits for the combined cycle units (Scenario 1)
Attachment B:	Derivation of emission limits for emergency units
Attachment C:	Annual emissions (combustion turbine and duct burner) – Scenario 2
Attachment D:	Auxiliary boiler emissions – Scenario 2
Attachment E:	Annual emissions (combustion turbine and duct burner) – Scenario 3
Attachment F:	Auxiliary boiler emissions – Scenario 3
Attachment G:	Potential to Emit (PTE) for all three scenarios
Attachment H:	Proposed CCCT emissions – Scenarios 2 and 3
Attachment I:	Proposed auxiliary boiler emissions – Scenarios 2 and 3
Attachment J:	DEQ air quality modeling analysis
Attachment K:	National Park Service air quality modeling analysis
Attachment L:	DEQ Guidance Memo regarding interim implementation of new source review for PM-2.5

ATTACHMENT A:

**Derivation of SO₂ and H₂SO₄ revised limits for the
combined cycle units (Scenario 1)**

Derivation of SO₂ and H₂SO₄ revised limits for the combined cycle units (Scenario 1)

SO₂

Given:

Sulfur content: 0.1 grain /100 scf

HHV of natural gas: 1,048 Btu/scf

Annual throughput: 35,920 MMscf /yr

MW of SO₂: 64

MW of S:32

Short-term SO₂ limit is:

$$(0.1 \text{ grain} / 100\text{scf}) \times (1 \text{ lb}/7000 \text{ grain}) \times (64/32) / (1048 \text{ Btu}/\text{scf}) = 0.000272\text{lb}/\text{MMBtu}$$

say 0.0003 lb/MMBtu

Equivalent annual limit is:

$$0.0003 \text{ lb}/\text{MMBtu} \times 35,920 \text{ MMscf}/\text{yr} \times (1048 \text{ Btu}/\text{scf}) \times (1 \text{ ton}/2000 \text{ lb}) = 5.65 \text{ tons}/\text{yr}$$

H₂SO₄

Given:

Sulfur content: 0.1 grain /100 scf

HHV of natural gas: 1,048 Btu/scf

Annual throughput: 35,920 MMscf /yr

MW of SO₂: 64

MW of H₂SO₄: 98

Assume:

20% of SO₂ may be converted to H₂SO₄

Short-term H₂SO₄ limit is:

$$0.2 \times 0.0003 \text{ lb}/\text{MMBtu} \times (98/64) = 0.0001 \text{ lb}/\text{MMBtu}$$

Equivalent annual limit is:

$$0.0001\text{lb}/\text{MMBtu} \times 35,920 \text{ MMscf}/\text{yr} \times (1048 \text{ Btu}/1 \text{ scf}) \times (1 \text{ ton}/2000 \text{ lb}) = 1.88 \text{ tons}/\text{yr}$$

ATTACHMENT B:

Derivation of emission limits for emergency units

Derivation of emission limits for emergency units

Firewater pump (EG1)

Given:

Operating hours per year: 500

Engine horsepower: 300

Applicable 40 CFR 60 Subpart IIII standard for NMHC + NO_x is 3.0 g/bhp-hr

So equivalent short-term NMHC + NO_x limit is:

$$\frac{3.0g}{bhp \cdot hr} \times 300bhp \times \frac{lb}{453.59g} = 2.0lbs / hr$$

Equivalent annual NMHC + NO_x limit is:

$$\frac{2.0lbs}{hr} \times \frac{500hrs}{yr} \times \frac{ton}{2000lbs} = 0.5tons / yr$$

Applicable 40 CFR 60 Subpart IIII standard for CO is 2.6 g/bhp-hr

So equivalent short-term CO limit is:

$$\frac{2.6g}{bhp \cdot hr} \times 300bhp \times \frac{lb}{453.59g} = 1.7lbs / hr$$

Equivalent annual CO limit is:

$$\frac{1.7lbs}{hr} \times \frac{500hrs}{yr} \times \frac{ton}{2000lbs} = 0.43tons / yr$$

Applicable 40 CFR 60 Subpart IIII standard for PM is 0.15 g/bhp-hr

So equivalent short-term PM limit is:

$$\frac{0.15g}{bhp \cdot hr} \times 300bhp \times \frac{lb}{453.59g} = 0.01lbs / hr$$

Equivalent annual PM limit is:

$$\frac{0.01lbs}{hr} \times \frac{500hrs}{yr} \times \frac{ton}{2000lbs} = 0.025tons / yr$$

Emergency generator (EG2)

Given:

Operating hours per year: 500
Engine horsepower: 2,235

Applicable 40 CFR 60 Subpart IIII standard for NMHC + NO_x is 4.8 g/bhp-hr

So equivalent short-term NMHC + NO_x limit is:

$$\frac{4.8g}{bhp \cdot hr} \times 2235bhp \times \frac{lb}{453.59g} = 23.6lbs/hr$$

Equivalent annual NMHC + NO_x limit is:

$$\frac{23.6lbs}{hr} \times \frac{500hrs}{yr} \times \frac{ton}{2000lbs} = 5.9tons/yr$$

Applicable 40 CFR 60 Subpart IIII standard for CO is 2.6 g/bhp-hr

So equivalent short-term CO limit is:

$$\frac{2.6g}{bhp \cdot hr} \times 2235bhp \times \frac{lb}{453.59g} = 12.8lbs/hr$$

Equivalent annual CO limit is:

$$\frac{12.8lbs}{hr} \times \frac{500hrs}{yr} \times \frac{ton}{2000lbs} = 3.2tons/yr$$

Applicable 40 CFR 60 Subpart IIII standard for PM is 0.15 g/bhp-hr

So equivalent short-term PM limit is:

$$\frac{0.15g}{bhp \cdot hr} \times 2235bhp \times \frac{lb}{453.59g} = 0.74lbs/hr$$

Equivalent annual PM limit is:

$$\frac{0.74lbs}{hr} \times \frac{500hrs}{yr} \times \frac{ton}{2000lbs} = 0.18tons/yr$$

ATTACHMENT C:

Annual emissions (combustion turbine and duct burner) – Scenario 2

Table B-4e
GE 7FA Potential to Emit - Combustion Turbine + Duct Burner

					SUSD	Prior to SUSD	Total
	Case 7-NG	Case 4-NG	Case 17-NG T+DB	Case 7-NG T+DB			
Temp	59	22	100	59			
Load	BASE	BASE	BASE	BASE			
Inlet Cooler	Off	Off	On	Off			
duct burner MMBtu/hr	-	-	500	500			
Evap. cooler status	Off	Off	On	Off			
Pound per Hour per Unit							
NOx	12.90	13.90	15.90	16.60			
CO	2.90	3.20	6.70	6.90			
VOC	0.90	0.90	3.80	3.90			
PM10	12.40	12.43	17.50	17.52			
SO2	0.31	0.33	0.38	0.39			
H2S04	0.27	0.29	0.34	0.35			
Pound per Hour (2 Units)							
NOx	25.80	27.80	31.80	33.20			
CO	5.80	6.40	13.40	13.80			
VOC	1.80	1.80	7.60	7.80			
PM10	24.80	24.86	34.99	35.03			
SO2	0.61	0.65	0.75	0.78			
H2S04	0.54	0.58	0.67	0.70			
Hours per Year							
w/ SU & SD Case 1	2,961	1,000	2,000	2,000	211	588	8,760
w/o SU & SD	3,760	1,000	2,000	2,000	-	-	8,760
Tons per Year							
w/ SU & SD							
NOx	38.20	13.90	31.80	33.20	19.38		136.48
CO	8.59	3.20	13.40	13.80	62.67		101.65
VOC	2.67	0.90	7.60	7.80	11.19		30.16
PM10	36.72	12.43	34.99	35.03			119.17
SO2	0.90	0.33	0.75	0.78			2.76
H2S04	0.80	0.29	0.67	0.70			2.46
w/o SU & SD							
NOx	48.50	13.90	31.80	33.20			127.40
CO	10.90	3.20	13.40	13.80			41.30
VOC	3.38	0.90	7.60	7.80			19.68
PM10	46.62	12.43	34.99	35.03			129.07
SO2	1.15	0.33	0.75	0.78			3.00
H2S04	1.02	0.29	0.67	0.70			2.68
max							
NOx							136.48
CO							101.65
VOC							30.16
PM10							129.07
SO2							3.00
H2S04							2.68

Table B-2a GE 7FA Startup and Shutdown Emissions												
Start Type	Emissions per Gas Turbine									Time to Emissions Compliance (minutes)		Time to Complete
	NOx			CO			VOC			GT#1	GT#2	Start-up minutes
	total (lb)	GT#1 (lb/hr)	GT#2 (lb/hr)	total (lb)	GT#1 (lb/hr)	GT#2 (lb/hr)	total (lb)	GT#1 (lb/hr)	GT#2 (lb/hr)			
Hot	40.0	68.6	36.4	117.0	200.6	106.4	28.0	48.0	25.5	35.0	66.0	90.0
Warm	40.0	68.6	36.4	117.0	200.6	106.4	28.0	48.0	25.5	35.0	66.0	130.0
Cold	96.0	87.3	59.4	199.0	180.9	123.1	31.0	28.2	19.2	66.0	97.0	250.0
Shutdown	57.0	380.0	380.0	200.0	1,333.3	1,333.3	29.0	193.3	193.3	9.0	9.0	-

(1) Emissions are for a single unit

Table B-2b Siemens 2 x 1 SGT6-5000F Startup and Shutdown Emissions											
Event	Duration (hours)	Emissions per Gas Turbine									
		NO _x		CO		VOC		SO ₂		PM	
		total (lb)	rate (lb/hr)	total (lb)	rate (lb/hr)	total (lb)	rate (lb/hr)	total (lb)	rate (lb/hr)	total (lb)	rate (lb/hr)
Startup	0.5	33.0	66.0	221.0	442.0	54.0	108.0	0.5	1.0	4.0	8.0
Shutdown	0.5	14.0	28.0	85.0	170.0	24.0	48.0	0.5	1.0	1.0	2.0

(1) Emissions are for a single unit

Table B-3a Startup and Shutdown Frequency	
Start Type	Annual Frequency
Turbine 1 Hot Start	124
Turbine 2 Hot Start	225
Turbine 1 Warm Start	15
Turbine 2 Warm Start	15
Turbine 1 Cold Start	6.5
Turbine 2 Cold Start	6.5

Table B-3b Startup and Shutdown Definitions				
Event	Minimum Down Time Prior to Startup (Hours)	Average Down Time Prior to Startup (Hours)	Maximum Down Time Prior to Startup (Hours)	Duration (Hours)
Start Up				
Hot	-	4.0	8.0	1.5
Warm	8.0	40.0	72.0	2.1
Cold	72.0	72.0	-	4.0
Shutdown	-	-	-	0.5

Table B-3c Combustion Turbine Operating Hours					
	CASE 7	CASE 4	CASE 17 + DB&PA	CASE 7 + DB&PA	Total Annual Hours of Power Operation
Temp	59	22	100	59	
Load	BASE	BASE	BASE	BASE	
Steam Injection	Off	Off	On	Off	
duct burner MMBtu/hr	-	-	500	500	
Evap. cooler status	Off	Off	On	Off	
With SU/SD	3,172	1,000	2,000	2,000	8,172
Without SU/SD	3,760	1,000	2,000	2,000	8,760

ATTACHMENT D:

Auxiliary boiler emissions – Scenario 2

Table B-6a
CPV Warren - Auxiliary Boiler Emissions - AB1
GE 7FA Option

<u>Steam Use</u>		<u>Steam Requirements lb/hr)</u>		
		Per Use	Total	Design Margin
Normal Start				
HRSG Sparging		-		
ST Gland Seals		11,000		
SJAE Sparging		16,000		
Hotwell sparging		8,000		
Aux Boiler Sparging		-		
Normal Use Total		35,000	35,000	5%
Rapid Response Addition				
Fuel heating			28,000	
Rapid Response Total			63,000	5%
Assume	feedwater temp	35 F		
	steam pressure	200 psig		
	feedwater enthalpy	3 Btu/lb		
	steam enthalpy	1,200 Btu/lb		
	boiler efficiency	81.7%		
	boiler capacity factor			
		Based on	Design	Total
		No of SU	Margin	
		35%	4%	39%

Heat Input
Rapid Response 97 MMBtu/hr

Potential to Emit - Rapid Response

Pollutant	lb/MMBtu	Ref	lb/hr	Ton/year
NOx	0.0110	1	1.07	1.82
CO	0.0360	1	3.49	5.96
VOC	0.0060	1	0.58	0.99
PM10	0.0005	1	0.05	0.08
SO2	0.0033	1	0.32	0.55
H2SO4	0.0003	2	0.02	0.04

1. Siemens Westinghouse Power Coporation Data - see Table B-6c
2. Assume 5% conversion of SO2 to H2SO4

ATTACHMENT E:

Annual emissions (combustion turbine and duct burner) – Scenario 3

Table B-4f
Siemens 2 x 1 SGT6-5000F Potential to Emit - Combustion Turbine + Duct Burner

	CASE 7	CASE 4	CASE 15 + DB&PA	CASE 7 + DB&PA	SU	SD	Prior to SUSD	Total
Temp	59	22	100	59				
Load	BASE	BASE	BASE	BASE				
Steam Injection	-	-	1.4	1.4				
duct burner MMBtu/hr	-	-	194	210				
Evap. cooler status	off	off	85%	85%				
Pound per Hour per Unit								
NOx	14.60	15.80	16.00	17.40				
CO	5.80	6.30	12.20	12.80				
VOC	1.80	2.00	4.00	4.30				
PM10	8.90	9.60	10.30	11.30				
SO2	0.60	0.65	0.65	0.70				
H2SO4	0.25	0.30	0.30	0.30				
Pound per Hour (2 Units)								
NOx	29.20	31.60	32.00	34.80				
CO	11.60	12.60	24.40	25.60				
VOC	3.60	4.00	8.00	8.60				
PM10	17.80	19.20	20.60	22.60				
SO2	1.20	1.30	1.30	1.40				
H2SO4	0.50	0.60	0.60	0.60				
Hours per Year								
w/ SU & SD Case 1	2,780	1,000	2,000	2,000	196	196	588	8,760
w/o SU & SD	3,760	1,000	2,000	2,000	-	-	-	8,760
Tons per Year								
w/ SU & SD - Case 1								
NOx	40.59	15.80	32.00	34.80	6.47	2.74		132.40
CO	16.12	6.30	24.40	25.60	43.32	16.66		132.40
VOC	5.00	2.00	8.00	8.60	10.58	4.70		38.89
PM10	24.74	9.60	20.60	22.60	0.10	0.10		77.74
SO2	1.67	0.65	1.30	1.40	0.78	0.20		6.00
H2SO4	0.70	0.30	0.60	0.60				2.20
w/o SU & SD								
NOx	54.90	15.80	32.00	34.80				137.50
CO	21.81	6.30	24.40	25.60				78.11
VOC	6.77	2.00	8.00	8.60				25.37
PM10	33.46	9.60	20.60	22.60				86.26
SO2	2.26	0.65	1.30	1.40				5.61
H2SO4	0.94	0.30	0.60	0.60				2.44
max								
NOx								137.50
CO								132.40
VOC								38.89
PM10								86.26
SO2								6.00
H2SO4								2.44

ATTACHMENT F:

Auxiliary boiler emissions – Scenario 3

Table B-6b
CPV Warren - Auxiliary Boiler Emissions - AB-1
Siemens 2 x SGT6-5000F Option

<u>Steam Use</u>		<u>Steam Requirements lb/hr)</u>			
		Per Use	Total	Design Margin	Total + Design Margin
Rapid Response Total			40,000	5%	42,000
Assume	feedwater temp	35 F			
	steam pressure	200 psig			
	feedwater enthalpy	3 Btu/lb			
	steam enthalpy	1,200 Btu/lb			
	boiler efficiency	81.7%			
	boiler capacity factor				
		Based on	Design	Total	
		No of SU	Margin		
		35%	4%	39%	
Heat Input					
	Rapid Response		62 MMBtu/hr		

Potential to Emit - Rapid Response

Pollutant	lb/MMBtu	Ref	lb/hr	Ton/year
NOx	0.0110	1	0.68	1.16
CO	0.0360	1	2.22	3.78
VOC	0.0060	1	0.37	0.63
PM10	0.0005	1	0.03	0.05
SO2	0.0033	1	0.20	0.35
H2SO4	0.0003	2	0.02	0.03

1. Siemens Westinghouse Power Corporation Data - see Table B-6c
2. Assume 5% conversion of SO2 to H2SO4

ATTACHMENT G:

Potential to Emit (PTE) for all three scenarios

Potential Emissions for Scenarios 1, 2 and 3

	Pollutant	Scenario 1 (GE 7FA)	Scenario 2 (GE 207 FA)	Scenario 3 (Siemens)	Existing Permit Limits
Combined Cycle Units Potential to Emit (tpy)	NO _x	141.8	136.5	137.5	141.8
	CO	97.2	101.7	132.4	97.2
	VOC	22.9	30.2	38.9	22.9
	PM-10	134.0	129.1	86.3	134.0
	SO ₂	5.7	3.0	6.0	12.2
	H ₂ SO ₄	1.9	2.7	2.4	3.7
Auxiliary Boiler Potential to Emit (tpy)	NO _x	-	1.8	1.1	-
	CO	-	5.9	3.8	-
	VOC	-	1.0	0.6	-
	PM-10	-	0.1	0.1	-
	SO ₂	-	0.5	0.3	-
	H ₂ SO ₄	-	0.0	0.0	-
Emergency Generator Potential to Emit (tpy)	NO _x	5.9	5.9	5.9	5.9
	CO	3.2	3.2	3.2	3.2
	VOC	-	-	-	-
	PM-10	-	-	-	-
	SO ₂	-	-	-	-
	H ₂ SO ₄	-	-	-	-
Fire Pump Engine Potential to Emit (tpy)	NO _x	0.5	0.5	0.5	0.5
	CO	0.4	0.4	0.4	0.4
	VOC	-	-	-	-
	PM-10	-	-	-	-
	SO ₂	-	-	-	-
	H ₂ SO ₄	-	-	-	-
Plant Totals Potential to Emit (tpy)	NO_x	148.2	144.3	144.7	148.2
	CO	100.8	111.2	139.8	100.8
	VOC	22.9	31.1	39.5	22.9
	PM-10	134.0	129.2	86.3	134.0
	SO₂	5.7	3.5	6.3	12.2
	H₂SO₄	1.9	2.7	2.5	3.7

ATTACHMENT H:

Proposed CCCT emissions – Scenarios 2 and 3

Table 4-1: GE 207FA Combustion Turbine Emissions Summary

Air Pollutant	Proposed Emission Limitations				Control Technology
	Base Load		Part Load		
	w/o Duct Burner Firing	w/ Duct Burner Firing	80% Load	60% Load	
PM ₁₀	12.45 lb/hr 0.0078 lb/MMBtu	17.56 lb/hr 0.0084 lb/MMBtu	12.38 lb/hr 0.0091 lb/MMBtu	12.32 lb/hr 0.0107 lb/MMBtu	Clean fuel, good combustion practices
NO _x	14.3 lb/hr 2.0 ppmvd	17.9 lb/hr 2.0 ppmvd	12.2 lb/hr 2.0 ppmvd	10.1 lb/hr 2.0 ppmvd	Dry low NO _x combustion, selective catalytic reduction
CO	3.3 lb/hr 1.2 ppmvd	7.3 lb/hr 1.5 ppmvd	2.5 lb/hr 1.2 ppmvd	2.2 lb/hr 1.2 ppmvd	Oxidation catalyst, good combustion practices
VOC	0.9 lb/hr 0.7 ppmvd	3.9 lb/hr 1.5 ppmvd	0.7 lb/hr 0.7 ppmvd	0.6 lb/hr 0.7 ppmvd	Oxidation catalyst, good combustion practices
SO ₂	0.34 lb/hr 0.00017 lb/MMBtu	0.42 lb/hr 0.00017 lb/MMBtu	0.29 lb/hr 0.00017 lb/MMBtu	0.24 lb/hr 0.00017 lb/MMBtu	Clean fuel, good combustion practices
H ₂ SO ₄	0.30 lb/hr 0.00016 lb/MMBtu	0.38 lb/hr 0.00016 lb/MMBtu	0.26 lb/hr 0.00016 lb/MMBtu	0.22 lb/hr 0.00016 lb/MMBtu	Clean fuel, good combustion practices

Table 4-2: Siemens SGT6-5000F Combustion Turbine Emissions Summary

Air Pollutant	Proposed Emission Limitations				Control Technology
	Base Load		Part Load		
	w/o Duct Burner Firing	w/ Duct Burner Firing	80% Load	60% Load	
PM ₁₀	9.90 lb/hr 0.0050 lb/MMBtu	11.30 lb/hr 0.0049 lb/MMBtu	8.90 lb/hr 0.0050 lb/MMBtu	8.20 lb/hr 0.0049 lb/MMBtu	Clean fuel, good combustion practices
NO _x	16.5 lb/hr 2.0 ppmvd	17.4 lb/hr 2.0 ppmvd	14.8 lb/hr 2.0 ppmvd	14.6 lb/hr 2.0 ppmvd	Dry low NO _x combustion, selective catalytic reduction
CO	7.2 lb/hr 1.8 ppmvd	12.8 lb/hr 2.5 ppmvd	7.2 lb/hr 1.8 ppmvd	7.2 lb/hr 1.8 ppmvd	Oxidation catalyst, good combustion practices
VOC	2.1 lb/hr 0.7 ppmvd	4.3 lb/hr 1.4 ppmvd	1.9 lb/hr 0.7 ppmvd	1.7 lb/hr 0.7 ppmvd	Oxidation catalyst, good combustion practices
SO ₂	0.65 lb/hr 0.00034 lb/MMBtu	0.70 lb/hr 0.00031 lb/MMBtu	0.60 lb/hr 0.00033 lb/MMBtu	0.60 lb/hr 0.00031 lb/MMBtu	Clean fuel, good combustion practices
H ₂ SO ₄	0.30 lb/hr 0.00013 lb/MMBtu	0.30 lb/hr 0.00012 lb/MMBtu	0.25 lb/hr 0.00012 lb/MMBtu	0.25 lb/hr 0.00012 lb/MMBtu	Clean fuel, good combustion practices

ATTACHMENT I:

Proposed auxiliary boiler emissions – Scenarios 2 and 3

Table 4-3: Auxiliary Boiler Emissions Summary - GE 207FA Option

Air Pollutant	Emissions			Control Technology
	lb/MMBtu	lb/hr	Ton/year	
PM ₁₀	0.0005	0.05	0.08	Good combustion practices, clean fuel
NO _x	0.011	1.07	1.82	Low NO _x burners, flue gas recirculation
CO	0.036	3.49	5.96	Good combustion practices
VOC	0.006	0.58	0.99	Good combustion practices
SO ₂	0.0033	0.32	0.55	Clean fuel
H ₂ SO ₄	0.0003	0.02	0.04	Clean fuel

Table 4-4: Auxiliary Boiler Emissions Summary - Siemens SGT6-5000F Option

Air Pollutant	Emissions			Control Technology
	lb/MMBtu	lb/hr	Ton/year	
PM ₁₀	0.0005	0.03	0.05	Good combustion practices, clean fuel
NO _x	0.011	0.68	1.16	Low NO _x burners, flue gas recirculation
CO	0.036	2.22	3.78	Good combustion practices
VOC	0.006	0.37	0.63	Good combustion practices
SO ₂	0.0033	0.20	0.35	Clean fuel
H ₂ SO ₄	0.0003	0.02	0.03	Clean fuel

ATTACHMENT J:

DEQ air quality modeling analysis

MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY *Office of Air Data Analysis and Planning*

629 East Main Street, Richmond, VA 23219
8th Floor

804/698-4000

TO: Sharon Foley, Air Permit Manager (VRO)

FROM: Mike Kiss, Coordinator - Air Quality Assessments Group (ODA)

DATE: August 31, 2007

SUBJECT: Analysis of Potential Class I and Class II Air Quality Impact Changes Due to Anticipated Amendments to the CPV - Warren Permit

C: Janardan Pandey (VRO), Laura Justin (VRO)

1. Introduction

The Office of Data Analysis' (ODA) Air Quality Assessments Group conducted an evaluation of the change in Class I and Class II air quality impacts expected to result from proposed changes to the CPV - Warren plant (CPV - Warren) configuration. Specifically, on June 8, 2007, CPV - Warren's consultant (TRC) submitted an analysis to DEQ which outlined the company's proposal to design a different turbine configuration, allowing two different combustion turbine generator (CTG) and heat recovery steam generator (HRSG) options. CPV - Warren is requesting an amendment to the current permit to allow the construction and operation of a combined-cycle electric generating facility which includes the option of selecting either two GE 207FA (similar to those already permitted) or alternatively two comparable Siemens SGT6-5000F gas turbines, with either option in a two-on-one configuration. Additionally, CPV - Warren is requesting to install a gas-fired auxiliary boiler to provide steam during plant down time and the plant start-up process for the two-in-one configuration.

2. Modeling Review

The changes in potential Class I and Class II air quality impacts from the proposed amended facility when compared to the previous permit were evaluated based on the following five criteria:

1. Short-term average stack parameters
2. Short-term and annual emissions
3. Comparison of changes to Building Profile Input Program (BPIP-PRIME) (building downwash) output due to differences in plant configuration.
4. Previous air quality modeling pollutant impacts compared to the National and Virginia Ambient Air Quality Standards (NAAQS/VAAQS) and Class II PSD increments.
5. Previous air quality modeling pollutant impacts compared to the Class I PSD increments and Air Quality Related Values (AQRV)

2.1. Short-term average stack parameters

A review of the proposed permit modifications indicated that will produce either improvements or insignificant differences in short-term average stack parameters and emission rates used in the dispersion modeling analyses that supported the original air permit application for the facility. Specifically, there is close agreement

between the modeled and proposed stack exit velocities across all combustion turbine operating scenario cases. As a result, minor differences in plume rise, dispersion and air quality impacts are anticipated. Additionally, the modeled stack exit temperatures used to develop the limits in the existing permit are slightly lower than those associated with the proposed permit modification; therefore, a higher plume rise, better dispersion, and lower air quality impacts are expected.

2.2. Short-term and annual emissions

Table 2-1 provides a brief description of the changes in short-term emission rates associated with the proposed permit amendment.

Table 2-1: Description of Changes in Short-Term Emission Rates

Pollutant	Description of Changes in Short-Term Emission Rates
NO _x	The previously modeled NO _x emission rates were conservative (i.e., significantly higher) for the 50 percent operating load cases, and were otherwise similar to the proposed permit modification emission rates, particularly with respect to the maximum duct burner firing cases that are associated with the maximum NO _x emissions.
CO	The previously modeled CO emission rates were generally similar to the proposed permit modification emission rates, and were identical or conservative (higher) for the maximum duct burner firing cases that are associated with the maximum CO emissions.
SO ₂	The previously modeled SO ₂ emission rates were extremely conservative (higher by a factor of approximately four or more) compared to the proposed permit modification emission rates.
VOC	The VOC emission rates in the current permit were generally similar to the proposed permit amendment emission rates, and conservative (higher) for the maximum duct burner firing cases that are associated with the maximum VOC emissions.
PM-10	The previously modeled PM-10 emission rates were very conservative (significantly higher) when compared to the proposed Siemens units and slightly more conservative (slightly higher) with respect to the new GE units.

In summary, the changes in short-term emissions when viewed on a pollutant-by-pollutant and collective basis demonstrate that the maximum short-term average emission rates used in the original modeling analysis for the CPV - Warren project are greater than or equal to the emission rates associated with the proposed permit modification.

In addition to the changes in short-term emissions, the proposed permit modifications will result in small decreases in the potential annual emissions of NO_x, SO₂ and PM-10, and minor increases in the potential annual emissions of CO and VOC (to account for the increase in startup and shutdown frequency and higher short term emissions for Siemens units). The decreases in the potential annual emissions of NO_x, SO₂ and PM-10 are expected to result in a decrease in annual average air quality impacts when compared to the previously modeled plant configuration. The minor increases in the potential annual emissions of CO and VOC are below the major modification thresholds for PSD review. These minor increases will result in correspondingly minor changes to the annual air quality impacts. It is important to point out that there are no annual average ambient air quality standards for CO or VOC.

2.3. Comparison of Changes to BPIP-PRIME Output Due to Differences in Plant Configuration

A review of the proposed facility configuration indicates that the locations and heights of the combustion turbine stacks remained unchanged from the previous dispersion modeling performed. The new auxiliary boiler stack will be attached to and have the same height as the stack for combustion turbine #1. Additionally, the proposed site plan modifications are minor with respect to the output of the Building Profile Input Program (BPIP-PRIME), which was used as input to the modeling analyses performed for the original air permit. As a result, the changes to the plant configuration are expected to have minimal or no impact on the air quality analysis results.

2.4. Previous Air Quality Modeling Pollutant Impacts Compared to the National and Virginia Ambient Air Quality Standards (NAAQS/VAAQS) and Class II PSD Increments

The June 2003 "Air Quality Modeling Report in Support of Permit Application for Proposed CPV - Warren Generating Facility – Class II Area Impact Analyses" describes the PSD Class II area dispersion modeling

analyses performed for the original air permit application for the CPV - Warren project. Table 2-2 summarizes those predicted maximum impacts also shows them as percentages of the NAAQS/VAAQS, PSD increments and modeling Significant Impact Levels (SILs).

Table 2-2: Maximum Modeled Concentrations Compared to Applicable Ambient Thresholds, Standards, and Increments ($\mu\text{g}/\text{m}^3$)

Criteria Pollutant	Averaging Period	Maximum Modeled Impact	Modeling Significant Impact Level (SIL)	Maximum Impact Percent of Modeling SIL	Class II PSD Increment	Maximum Impact Percent of Increment	NAAQS/VAAQS	Maximum Impact Percent of NAAQS/VAAQS
		(A)	(B)	$100 \times (A/B)$	(C)	$100 \times (A/C)$	(D)	$100 \times (A/D)$
Nitrogen Dioxide (NO_2) ⁵	Annual	0.4	1	40.0%	25 ²	1.6%	100 ²	0.4%
Carbon Monoxide (CO)	1-Hour	9.5	2000	0.5%	N/A	N/A	40,000 ¹	0.0%
	8-Hour	3.4	500	0.7%	N/A	N/A	10,000 ¹	0.0%
Sulfur Dioxide (SO_2)	3-Hour	1.1	25	4.4%	512 ¹	0.2%	1300 ¹	0.1%
	24-Hour	0.6	5	12.0%	91 ¹	0.7%	365 ¹	0.2%
	Annual	0.06	1	6.0%	20 ²	0.3%	80 ²	0.1%
Particulate Matter (PM_{10})	24-Hour	3.8	5	76.0%	30 ¹	12.7%	150 ³	2.5%
	Annual	0.3	1	30.0%	17 ²	1.8%	50 ⁴	1.5%

¹ Not to be exceeded more than once per year

² Not to be exceeded

³ Fourth highest concentration over a 3-year period

⁴ Average of three annual average concentrations

⁵ Total NO_x conservatively reported, unadjusted for conversion to NO_2

N/A = Not applicable.

Based on the information contained in Table 2-2, it is clear that the previously modeled maximum predicted air pollutant impacts that were small fractions of the National and Virginia Ambient Air Quality Standards (NAAQS/VAAQS) and Class II PSD increments, and that were well below SILs for Class II areas. Specifically, none of the maximum predicted impacts exceeded 3 percent of any NAAQS/VAAQS or 13 percent of any Class II PSD increment. Furthermore, the information summarized in Sections 2.1 through 2.3 of this report demonstrates that the proposed project modifications will improve or have no perceptible effect on the already insignificant PSD Class II area air quality impacts predicted for the CPV Warren project.

2.5. PSD Class I Area Impacts

The September 2003 "Air Quality Modeling Report in Support of Permit Application for the Proposed CPV Warren Generating Facility – Class I Area Impact Analyses" describes the PSD Class I area dispersion modeling analyses performed for the original air permit application. Tables 2-3 and 2-4 below summarize the AERMOD modeling analysis results for the Class I area (Shenandoah National Park) located within 50 kilometers of the project. These tables include maximum predicted impacts for the CPV - Warren project and also show them as percentages of the PSD increments and modeling SILs.

**Table 2-3: CPV - Warren AERMOD Single-Source Modeling Results
Class I Area Summary ($\mu\text{g}/\text{m}^3$)**

Pollutant	Averaging Period	Maximum Modeled Impact	Modeling Significant Impact Level (SIL)	Maximum Impact Percent of Modeling SIL	Class I PSD Increment	Maximum Impact Percent of Increment
NO ₂	Annual	0.04	0.1	40.0%	2.5	1.6%
PM ₁₀	24-hour	0.7	0.3	233.3%	8	8.8%
	Annual	0.04	0.2	20.0%	4	1.0%
SO ₂	3-hour	0.7	1.0	70.0%	25	2.8%
	24-hour	0.1	0.2	50.0%	5	2.0%
	Annual	0.007	0.1	7.0%	2	0.4%

**Table 2-4: CPV - Warren PM₁₀ Multi-Source Modeling Results
Class I Area Summary ($\mu\text{g}/\text{m}^3$)**

Year	1 st Highest 24-Hour	2 nd Highest 24-Hour	Class I PSD Increment	Percent of PSD Class I Increment Consumed by 2 nd Highest 24-Hour
1988	0.8	0.7	8	8.8%
1989	0.8	0.7	8	8.8%
1990	0.6	0.4	8	5.0%
1991	0.5	0.4	8	5.0%
1992	0.4	0.4	8	5.0%

The original AERMOD modeling analyses produced maximum predicted air pollutant impacts that were small fractions of the PSD increments, and that, with the exception of the maximum 24-hour average PM-10 impact, were well below the modeling SILs for Class I areas. Specifically, none of the maximum predicted impacts exceeded 9 percent of any Class I PSD increment.

In addition to the near-field AERMOD results, the original modeling analysis included CALPUFF dispersion modeling performed for the PSD Class I areas located further than 50 kilometers from the project. The maximum predicted air pollutant impacts were very small fractions of the PSD increments, and were small fractions of the modeling SILs for PSD Class I areas.

Based on the previously modeled emission rates, the predicted impacts were determined by the United States Department of Interior, National Park Service (NPS), to have no adverse impacts on Air Quality Related Values (AQRVs) in the Class I areas of interest. The emission rates of the various pollutants considered in the visibility, regional haze and deposition modeling analyses (i.e., NO_x, SO₂, PM-10, SO₄²⁻, NO₃⁻, fine particles, organic carbon, and HNO₃) are expected to be reduced based on the proposed changes to the facility's emission rates. Therefore, it is logical to conclude that the proposed changes will result in AQRV impacts lower than or equal to the minimal or non-adverse impacts previously reported.

In order to test the aforementioned premise, the NPS conducted PLUVUE II modeling for a representative set of data to ascertain the impact of the proposed changes on plume impairment. Specifically, the NPS modeling included the following assumptions:

1. 36 hours of the 66 hours that were greater or equal to the FLAG thresholds of 1.0 for delta E or Contrast of 0.02 from the initial modeling analysis were modeled.
2. 4 view areas (Dicky Ridge, Lands Run, Compton Gap and Signal Knob) were evaluated.
3. All hours that had delta E greater than 1.0 for all 4 views were modeled
4. Contrast modeling was conducted for all hours that were greater than 0.030 at Dicky Ridge and Lands

Run.

5. Contrast modeling was conducted for all hours that were greater than 0.025 for Signal Knob.
6. Contrast modeling was conducted for all hours that were greater than 0.024 for Compton Gap.
7. The various contrast thresholds were chosen by the NPS because a minimum of 5 hours was needed at each view to perform a robust plume impairment analysis.

The NPS concluded that the proposed new GE turbines are slightly better in terms of air quality impact than the currently permitted GE units. This was primarily the result of the change to reduced sulfur content in the natural gas pipeline. Furthermore, the impact from the Siemens turbines was much less than the GE units. The differences between the GE and Siemens units may be attributed to a difference in vendor guarantee and not actual emission rates when tested in the field. A summary of the PLUVUE II modeling is provided in Table 2-5.

Table 2-5: Summary of NPS PLUVUE II Modeling to Determine Changes in Plume Impairment

	Delta E >1.0 CURRENT GE	Contrast >0.02 CURRENT GE	Delta E >1.0 NEW GE	Contrast >0.02 NEW GE	Delta E >1.0 SIEMENS	Contrast >0.02 SIEMENS
COMPTON GAP 5 HOURS MODELED	2 HOURS	5 HOURS	2 HOURS	5 HOURS	0 HOURS	0 HOURS
Maximum Impact	1.397	0.029	1.306	0.027	0.818	0.017
DICKEY RIDGE 14 HOURS MODELED	7 HOURS	14 HOURS	6 HOURS	13 HOURS	3 HOURS	10 HOURS
Maximum Impact	2.312	0.084	2.211	0.080	1.397	0.033
LANDS RUN 12 HOURS MODELED	5 HOURS	12 HOURS	2 HOURS	12 HOURS	1 HOURS	5 HOURS
Maximum Impact	1.827	0.048	1.710	0.044	1.065	0.027
SIGNAL KNOB 5 HOURS MODELED	3 HOURS	5 HOURS	3 HOURS	5 HOURS	0 HOURS	1 HOURS
Maximum Impact	1.398	0.034	1.300	0.032	0.812	0.020

In summary, the proposed project modifications will improve or have no noticeable effect on the already insignificant or otherwise acceptable PSD Class I area air quality impacts predicted for the CPV - Warren project.

3. Conclusions

The proposed project modifications will improve or have no perceptible affect on air quality. The analysis of the proposed changes demonstrates that there will be minimal differences with respect to both the existing air permit and the data used to perform the dispersion modeling analyses that supported the original air permit application for the CPV - Warren project.

ATTACHMENT K:

National Park Service air quality modeling analysis



United States Department of the Interior

NATIONAL PARK SERVICE
Shenandoah National Park
3655 U.S. Hwy. 211 East
Luray, Virginia 22835-9036

IN REPLY REFER TO:

N3615 (2350)

September 26, 2007

Ms. Sharon Foley
Air Permit Manager
Virginia Department of Environmental Quality
Valley Regional Office
4411 Early Road, P.O. Box 3000
Harrisonburg, Virginia 22801

Dear Ms. Foley:

The National Park Service (NPS) has considered the request of Competitive Power Ventures (CPV) to amend its current permit from the Virginia Department of Environmental Quality (VDEQ) for its CPV Warren County project. CPV has proposed to replace the permitted Warren County equipment of two natural gas fired "one-on-one" Combustion Turbine Generator/Heat Recovery Steam Generator (CTG/HRSG) units with a single natural gas fired two-on-one CTG/HRSG unit. At the time of the submittal to VDEQ, CPV had narrowed the choice of equipment to either two Siemens SGT6-5000F gas turbines with a HRSG or two GE 207FA gas turbines with a HRSG. The revised permit will also include an auxiliary gas-fired boiler, which was not in the original permit, to provide steam during plant down time and plant start-up operations.

We evaluated the effect of the changes in equipment to impacts to Shenandoah National Park (NP), a mandatory Class I area administered by the NPS, which is located seven kilometers south of the proposed Warren County project. In the air quality impact analysis for the original permit, the coherent plume analysis with the EPA PLUVUE 2 model proved to be the most limiting component of the Class I air quality impact analysis. The first permit analysis had a frequency of the potential plume impacts of 66 one-hour occurrences over a period of five years. The FLAG contrast perceptibility threshold is a value of 0.02. The magnitude of the contrast impacts ranged between 0.02 and 0.03 for a total of 41 hours. The FLAG color difference (ΔE) perceptibility threshold is a value of 1.0. The magnitude of ΔE ranged mostly between 1.0 and 2.0 for 14 hours. The ΔE impacts also exceeded a value of 2.0 for two hours over the five year period modeled. The duration of the impacts lasted no more than one hour on all but three days, and for

those three days each had two consecutive hours of impacts. The extent of the 66 hours of impacts had seven occurrences with two locations (Dickey Ridge and Signal Knob) affected during the same hour. The remainder of the hours of impacts (59) only affected one location per hour.

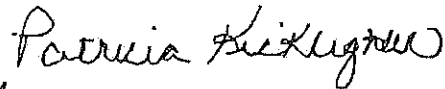
To understand the implications of the proposed equipment change to the permit, we assessed the potential coherent plume impacts of the new equipment to Shenandoah NP. We modeled both proposed new turbines, Siemens and GE, and their respective HRSG with duct burners, at maximum emission rates from Table 1 (Case 1) from the recently submitted "Analysis of Potential Air Quality Impact Changes Due to Anticipated Amendments to the CPV Warren Permit to Construct and Operate." The stack parameters used in the analysis were from "Form 7" of the application to the VDEQ. We developed the individual hours of meteorological conditions and observer locations from Appendix E-3 "List of Hours with Values Over Levels of Concern" from the first application.

We modeled 36 of the 66 hours that were greater than or equal to the FLAG thresholds of 1.0 for ΔE or 0.02 for Contrast from the first permit results found in Appendix E-3. Only the four observer locations which had significant impacts in the first analysis, Compton Gap, Dickey Ridge, Lands Run, and Signal Knob, were modeled. Since the Shenandoah Valley observer location had no impacts above the threshold levels in the first analysis, it was not modeled in this re-analysis. The four observer locations did not have an equal number of impacts or magnitude of impacts. Therefore, we developed a method to evaluate at least five significant impact meteorological conditions at the four observer locations for each of the two proposed new turbines. We modeled all hours that had ΔE greater than 1.0 for all four observer locations at Compton Gap, Dickey Ridge, Lands Run, and Signal Knob. To evaluate plume contrast impacts, we modeled all of the hours that had contrast values in the first permit analysis greater than 0.030 for Dickey Ridge and Lands Run. In order to have at least five hours evaluated from each observer location, we also modeled all hours that had contrast impacts greater than 0.025 at Signal Knob and 0.024 at Compton Gap. Therefore, a total of 14 hours, 12 hours, five hours and five hours were modeled at Dickey Ridge, Lands Run, Signal Knob and Compton Gap, respectively. We then compared the impacts from the new turbines to the results found in Appendix E-3, and paired the downwind distances for each meteorological condition at each respective observer location with the results from the earlier analysis. The analysis indicates that in every instance, the proposed new turbines, both the Siemens and GEs, produced lower impacts than the earlier permitted turbines. The results are presented in the enclosed Table 1, which compares the impacts from the "Old GE" turbines and the new proposed Siemens and GE turbines.

The results of the new analysis indicate that the Siemens turbines clearly produce lower coherent plume impacts at Shenandoah NP, with 20 impacts greater than the PLUVUE thresholds verses 47 impacts greater than the PLUVUE thresholds from the new GE turbines. Therefore, as part of the Best Available Control Technology component of the PSD program, and the proximity of this project to Shenandoah NP, the NPS recommends that the VDEQ strongly consider requiring CPV to install the cleaner turbines.

Thank you for the opportunity to review the CPV application, and the cooperation you have shown throughout the review of this project. If you require further information regarding this matter, please contact John Notar at (303) 969-2079.

Sincerely,


for Chas Cartwright
Superintendent

Enclosure

TABLE 1

	Delta E >1.0 OLD GE	Contrast >0.02 OLD GE	Delta E>1.0 NEW GE	Contrast >0.02 NEW GE	Delta E>1.0 SIEMENS	Contrast >0.02 SIEMENS
COMPTON GAP: 5 HOURS MODELED	2 HOURS	5 HOURS	2 HOURS	5 HOURS	0 HOURS	0 HOURS
MAX	1.397	0.029	1.306	0.027	0.818	0.017
DICKEY RIDGE: 14 HOURS MODELED	7 HOURS	14 HOURS	6 HOURS	13 HOURS	3 HOURS	10 HOURS
MAX	2.312	0.084	2.211	0.080	1.397	0.033
LANDS RUN: 12 HOURS MODELED	5 HOURS	12 HOURS	2 HOURS	12 HOURS	1 HOURS	5 HOURS
MAX	1.827	0.048	1.710	0.044	1.065	0.027
SIGNAL KNOB: 5 HOURS MODELED	3 HOURS	5 HOURS	3 HOURS	5 HOURS	0 HOURS	1 HOURS
MAX	1.398	0.034	1.300	0.032	0.812	0.020

ATTACHMENT L:

**DEQ Guidance Memo regarding interim implementation of
new source review for PM-2.5**

COMMONWEALTH OF VIRGINIA
Department of Environmental Quality

Subject: Air Guidance Memo No. APG-307
Interim Implementation of New Source Review for PM_{2.5}

To: Agency Deputy Directors, Regional Directors, Regional Deputy Directors, Regional Air Permit Managers

From: James E. Sydnor
Air Division Director

Date: October 10, 2006

Copies: Office of Air Permits Director, Office of Regulatory Development Director, Office of Air Compliance Director

Summary:

This policy adopts the current Environmental Protection Agency (EPA) guidance on interim implementation of New Source Review (NSR) for PM_{2.5}.

Electronic Copy:

An electronic copy of this guidance is available on the DEQ website at <http://www.deq.virginia.gov/>.

Contact Information:

Please e-mail Tamera Thompson or call (804) 698-4502 with any questions regarding the application of this guidance.

Background

A new National Ambient Air Quality Standard (NAAQS) for PM_{2.5} went into effect on September 16, 1997 and was revised on September 22, 2006. When the standard went into effect, PM_{2.5} became a regulated pollutant under the Clean Air Act and subject to major NSR under Title I of the Clean Air Act. Although PM_{2.5} is covered under NSR, the measurement, calculation and modeling of PM_{2.5} had not been fully developed and EPA issued guidance both in October 1997 and April 2005 addressing the interim implementation of PM_{2.5} until such time as EPA promulgates standards or guidelines. Both guidance documents direct permitting authorities to use PM₁₀ as a surrogate for PM_{2.5}.

On September 1, 2006, Virginia's Major New Source Review regulations went into effect and incorporates a PM_{2.5} significance level of 10 tpy.

Definitions

The terms of this policy shall have the same meaning as the terms defined in 9 VAC 5 Chapter 10 and

Articles 8 and 9 of Part II of 9 VAC 5 Chapter 80.

Policy

EPA has issued guidance on the interim implementation of Major New Source Review for PM_{2.5} in the following documents:

Interim Implementation of New Source Review Requirements for PM_{2.5} – October 23, 1997

Implementation of New Source Review Requirements in PM_{2.5} Nonattainment Areas – April 5, 2005

For the purpose of implementing Major New Source Review, DEQ shall use PM₁₀ as a surrogate for PM_{2.5}, as specified in the EPA guidance documents, until such time as:

- DEQ establishes a more appropriate implementation methodology; or
- EPA promulgates revised implementation guidance or policy; or
- EPA promulgates final regulations

Virginia sources under 9 VAC 5 Chapter 190 and 9 VAC 5 Chapter 230 with a site-wide emissions cap, may use the PM₁₀ limit as a surrogate PM_{2.5} limit until such time as noted above or until the source has received a PM_{2.5} plantwide applicability limit (PAL) as established by Articles 8 or 9 of Part II of 9 VAC 5 Chapter 80, whichever comes first.